

Commonwealth of Kentucky
Division for Air Quality
PERMIT STATEMENT OF BASIS

TITLE V PERMIT NO: V-02-043 REVISION 3
Louisville Gas and Electric Company
P.O. Box 32010, Louisville, Kentucky, 40232

HERBERT CAMPBELL, REVIEWER
JULY 26, 2007
SOURCE I.D. #: 021-223-00002
SOURCE A.I. #: 4054
ACTIVITY #: APE 20070001

CURRENT PERMITTING ACTION: V-02-043R3

BACKGROUND

On December 1, 2004, LG&E submitted to the Division a Prevention of Significant Deterioration air permit application (hereinafter referred to as "2004 Application") to construct and operate a new 750 MW net nominal supercritical pulverized coal (SPC) boiler and associated support equipment, for electricity generation from LG&E at its existing Trimble County facility. The application was logged administratively complete on January 29, 2005. On November 17, 2005 the Division issued a draft PSD Construction/ Title V Operating Permit (Permit # V-02-043R2) for the proposed Trimble County Unit 2 Project. The final air permit was issued on January 4, 2006.

After receiving the final air permit for the proposed project, the applicant has contracted with an environmental engineering & design company for any revisions to the project design. In August 2006, LG&E submitted a minor revision application to the Division. On February 13, 2007, the Division received an application for significant revision to amend the permit issued to LG&E for permitting design revisions to the SPC boiler project.

These revisions, which include the August 2006 minor revision and the February 2007 significant revisions, are being reviewed as a significant permit revision under 401 KAR 52:020 Section 16. The applicant noted that the information and analyses contained in the 2004 Application remain valid unless a change was noted. A summary of the project revisions, changes to the project's potential-to-emit (PTE), regulatory applicability, and the model-predicted maximum impacts as a result of these revisions are presented in the application that was submitted to Division on February 13, 2007.

PROJECT SUMMARY

As part of the revisions, Emission Unit 31 will also be equipped with a dry electrostatic precipitator (DESP), powdered activated carbon (PAC) injection and hydrated lime injection. The DESP will ensure that saleable fly ash is captured prior to potential contamination due to PAC injection for mercury control. The hydrated lime injection will assist in proper conditioning of the Pulse Jet Fabric Filter (PJFF) bags by potentially reducing SO₃ emissions for some fuel combinations. However, it has not been proposed for as an alternative SO₃ emission reduction technology.

The potential emissions from the new boiler (Emission Unit 31) in the 2004 Application were not changed because the proposed modifications do not affect the boiler. Potential emissions from the auxiliary boiler (Emission Unit 32) increased due to an increase in the auxiliary boiler size and 1,000 hours of additional annual operation. The potential emissions of sulfur dioxide and sulfuric acid mist decreased due to the switch to ultra low sulfur (ULS) fuel oil in the new auxiliary boiler (Emission Unit 32). The potential emissions from the emergency generator (Emission Unit 33) also decreased as a result of the proposed change to ULS fuel oil along with the proposed change in the number of hours of operation on an annual basis. Additionally, the revised design indicates that the originally proposed emergency diesel firewater pump (insignificant activity) and the three existing auxiliary boilers (Emission Units 7, 8 and 9) are not required. The elimination of emissions from these sources will further decrease the overall Project's PTE.

Material handling emissions increased as a result of the proposed revisions due to several changes. Specifically, these changes consisted of (1) the addition of material handling silos (waste ash, hydrated lime and PAC), (2) movement of the proposed conveyers transfer points with their currently established BACT controls, (3) new conveyor transfer points with the BACT controls, and (4) new haul road emissions due to additional haul road length to extend the previous route to the northwest corner of the ash pond and the change in methodology used to calculate these emissions. Additionally, there was a significant decrease in particulate emissions associated with ash transfer design change from truck transport to a wet transfer of the fly ash to the pond.

With the change to ULS fuel oil, the heating value of the fuel oil fired for the auxiliary boiler (Emission Unit 32), emergency generator (Emission Unit 33), and for startup operations of the Unit 2 boiler (Emission Unit 31), along with the increase in hours of operation for the auxiliary boiler, the amount of fuel oil utilized at the facility increased. The increase in oil consumption will cause an increase to the turnover rates of the fuel oil storage tanks, thus the VOC emissions from the fuel oil storage tank will insignificantly increase. Fuel oil storage tanks are considered an insignificant activity and are listed as such in the permit.

The emission calculations for the Linear Mechanical Draft Cooling Tower (LMDCT) (Emission Unit 41), were updated based on a more conservative assumption that 100 percent of the salt is PM₁₀. As a result, the calculated total PM emissions from the LMDCT increased. However, potential PM emissions from the natural draft cooling tower (Emission Unit 20) significantly decreased as a result of the proposed modifications to reduce existing drift rate from 0.008% to 0.0005%. This change to the natural draft cooling tower's drift eliminators will occur prior to Emission Unit 31 commencing operation.

The applicant used the same methodology presented in the 2004 Application to determine the emissions change from the project revisions. These emissions were incorporated into the Project's potential-to-emit calculations used to determine the PSD/NSR major modification determination. The methodology to calculate these emissions can be found in Section 2 and Appendices C and D of the February 2007 Application. Table 3.1 depicts the PTE emissions that were presented in the 2004 Application document while Table 3.4 illustrates the PTE resulting from the proposed Project's optimizations. The net emissions resulting from the proposed revisions based on the refined design are presented in Table 3.5. As presented in Table 3.5, the emissions of the proposed changes are below their applicable significant emission increase threshold for a major modification under PSD. Likewise, as shown in Table 3.4, there are no changes to the project's applicability under the original PSD review process from what was determined for the 2004 Application and established as the basis for the subsequently issued permit in January 2006.

**TABLE 3.4 – Overall Project Net Emissions Increase for
PSD-Regulated Pollutants Based Upon Optimization Project Changes**

Pollutants	Net Emissions Increase (tpy)
Carbon Monoxide (CO)	3,050.2
Nitrogen Oxides (NO _x)	35.1*
Particulate Matter (PM/PM ₁₀)	559.0
Sulfur Dioxide (SO ₂)	38.1**
Volatile Organic Compounds (VOC)	97.5
Sulfuric Acid (H ₂ SO ₄) Mist	116.5
Fluorides	6.8
Lead (Pb)	0.15
Total Reduced Sulfur	Negligible
Reduced Sulfur Compounds	Negligible
Hydrogen Sulfide	Negligible
Mercury (Hg) (non PSD pollutant)	0.043

* On January 4, 2005, the Division for Air Quality (Division) approved LG&E's minor permit revision that contained an enforceable emissions limit such that the consecutive twelve-month rolling total of NO_x emissions from Emission Unit 1 shall not exceed 5,556 tpy. The emissions decrease for Emission Unit 1 of 1,485 tpy of NO_x is realized as both contemporaneous and creditable. The proposed project is not subject to PSD review for NO_x. The project optimizations further decrease the potential emissions of NO_x from the project by 2.9 tpy from those potential emissions indicated in the 2004 Application.

** On May 2, 2005, the Division received LG&E's minor permit revision that contained an enforceable emissions limit such that the consecutive twelve month rolling total of SO₂ emissions from existing Emission Unit 1 shall not exceed 4,822 tpy. The emissions decrease for Emission Unit 1 of 3,225 tpy of SO₂ is realized as both contemporaneous and creditable. The Division approved this in the final permit issued. The proposed project is not subject to PSD review for SO₂. The project optimizations further decrease the potential emissions of SO₂ from the project by 0.9 tpy from those potential emissions indicated in the 2004 Application.

**TABLE 3.5 – Change in Potential Annual Emissions
Associated with Project Optimizations as
Compared to the 2004 Application**

Pollutants	Net Emissions Increase (tpy)
Carbon Monoxide (CO)	9.4
Nitrogen Oxides (NO _x)	-2.9
Particulate Matter (PM/PM ₁₀)	-8.5
Sulfur Dioxide (SO ₂)	-0.9
Volatile Organic Compounds (VOC)	-0.3
Sulfuric Acid (H ₂ SO ₄) Mist	-5.8E-2
Fluorides	2.2E-2
Lead (Pb)	6.7E-4
Total Reduced Sulfur	Negligible
Reduced Sulfur Compounds	Negligible
Hydrogen Sulfide	Negligible
Mercury (Hg) (non PSD pollutant)	0.00

Using the same methodology to determine the net emissions increases for the proposed Project for NO_x and SO₂ for the 2004 Application, the Division determined the contemporaneous period for the Project and identified all emissions increases and decreases that are contemporaneous and creditable pursuant to 401 KAR 51:001 Section (1)(146). The contemporaneous period for the proposed Project is the period 60-months prior to the start of construction through the period in which the Project starts operation. For this Project, the construction period is projected at 5-years, resulting in a 10-year period. No other creditable emission increases or decreases have occurred within the contemporaneous period for the Project. Further, the Trimble County Generating System has not undergone PSD for any other project since the most recent Unit 2 (Emission Unit 31) project. Table 3.6 summarizes the PSD netting for NO_x and SO₂. The proposed project revisions further decrease the Project's PTE through the revised netting calculations, and therefore does not affect the Division's previous netting determination. The Unit 1 annual tonnage limit for NO_x and SO₂ of 5,556 tpy and 4,822 tpy, respectively, will remain enforceable.

TABLE 3.6 – PSD Netting Summary (TPY)

	Emission Unit 1 Creditable Decreases	2004 Project Emissions Increases	2004 Net Emissions Increase	2007 Net Emissions Increase	Project Net Emissions Increase	Significant Emissions Rate*
NO _x	1,485	1,523	38	-2.9	35.1	40
SO ₂	3,225	3,264	39	-0.9	38.1	40

* Significant emission rate as given in 401 KAR 51:001 Section 1(221)

In summary, all pollutants with the exception of CO, lead, and fluorides decrease the Project's overall PTE as a result of the revisions. However, these noted potential emission increases do not alter the applicability of the project with respect to PSD/NSR. It should be noted that the 2004 Application netted out of PSD review for NO_x and SO₂ emissions. As Table 3.5 indicates, the proposed revisions further decrease the emissions of these pollutants. Therefore, the decrease in emissions of SO₂ and NO_x resulting from the proposed project revisions will not change the project's classification since there will not be a significant net emissions increase. The emission reductions of SO₂ and NO_x as noted above are enforceable through the emission and operation limits on the new auxiliary boiler and the removal of the three existing auxiliary boilers from the permit upon start up of the new boiler.

REGULATORY REVIEW

This section presents a discussion of the air quality regulations applicable to this project in addition to the PSD requirements. In some cases the emission limit or technology standard based on these regulations may be superseded by the BACT requirements which are more stringent under PSD (see Section 5, Best Available Control Technology Review).

PROJECT REGULATORY SUMMARY

The project revisions have resulted in insignificant changes to the project's original potential-to-emit as specified in Table 3.4. Additionally, the PSD applicability on a pollutant-by-pollutant basis and the associated BACT determination for new equipment remain unchanged. Existing equipment will continue to operate within their permitted emission limits. The applicant has demonstrated that the insignificant change in emissions and associated impacts due to the design revisions will not result in any significant issues with respect to Kentucky air quality regulations. Consequently, the Division is treating the project revisions as a revision to the PSD/Title V Permit (Permit # V-02-043R2), issued in January 2006.

The following regulations apply to the subsequent optimizations of the proposed project.

New Source Performance Standards (NSPS)

The Federal Clean Air Act (CAA) directed U.S. EPA to establish New Source Performance Standards, or NSPS, for specific industrial categories. There are three NSPS applicable requirements to the subsequent optimizations of the proposed project.

New Source Performance Standards for Non-Metallic Mineral Processing Plants

As part of the project revisions, the applicant has proposed to install a new hydrated lime silo and injection system prior to the Emission Unit 31 fabric filter to prevent deterioration of the filter media. The hydrated lime injection will assist in proper conditioning of the PJFF bags. In addition, there will be a potential reduction in SO₃ emissions for some fuel combinations. However, it has not been proposed as an alternative SO₃ emission reduction technology. Lime and limestone are nonmetallic minerals, and all lime/limestone handling, transfer, and storage systems will be subject to the requirements of 40 CFR Part 60 Subpart OOO. As described in the 2004 Application, this Project does not involve the installation of new limestone process equipment, but the existing limestone handling, transfer, and storage systems will be used with minor modifications. The existing limestone handling, conveying, and storage systems are in compliance with the requirements of Subpart OOO, and the revised systems will continue to be in compliance after Unit 2 (Emission Unit 31) begins operations.

New Source Performance Standards for Small Industrial-Commercial-Institutional Steam Generating Units

The proposed design revisions will not alter the NSPS Subpart Dc applicability. As part of the project revisions, the fuel proposed for auxiliary boiler (Emission Unit 32) was changed from No. 2 distillate fuel oil containing 0.05% sulfur to an ultra-low sulfur diesel (ULSD, 0.0015 percent) which meets ASTM Grade No. 2-D S15 specifications. The requirements of NSPS Subpart Dc will continue to apply to the 100 MMBtu per hour, ULSD oil fired auxiliary boiler and will demonstrate compliance with the opacity emission standard by reference Method 9.

New Source Performance Standards for Stationary Compression Ignition Internal Combustion Engines

The compression ignition (CI) NSPS 40 CFR Part 60 Subpart IIII, will be applicable to the emergency generator (Emission Unit 33) that will now operate no more than 50 hours per year and meet the Subpart IIII definition of an emergency generator. This generator was previously categorized as a back-up generator. The engine will be manufactured after 2007 and will meet the Tier II Standards. The Division requires manufacturers of the new engines to certify compliance with this standard. LG&E proposes to purchase and install a manufacturer's certified Tier II compliant engine to comply with the requirements of this standard.

Maximum Achievable Control Technology Standards (MACT)

Associated impacts due to the design optimizations are as follows.

40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters

The auxiliary steam boiler (Emission Unit 32) is an affected source under the Industrial Boiler MACT, 40 CFR Part 63, Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters. The Industrial Boiler MACT was published on September 13, 2004 (69 FR 55218, September 13, 2004). The size of the auxiliary boiler has increased as part of the design optimizations and, based on its heat input rating of 100 MMBtu per hour and capacity factor, will be considered as a new large liquid fuel boiler under the MACT. 40 CFR Part 63, Subpart DDDDD, places restrictions on PM, HCl, and CO emissions from new large liquid fuel fired boilers. PM is restricted to 0.03 lb/MMBtu,

HCl is restricted to 0.0005 lb/MMBtu, and CO is restricted to 400 ppmvd (30-day rolling average). The CO limit is a work practice standard. Being an affected new source, the auxiliary steam boiler has to demonstrate compliance with the MACT requirements upon startup. LG&E will demonstrate initial compliance by including a signed statement in the Notification of Compliance Status that indicates that the auxiliary steam boiler will burn only liquid fossil fuels other than residual oils, either alone or in combination with other gaseous fuels.

40 CFR Part 63, Subpart ZZZZ, National Emissions Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

The emergency generator (Emission Unit 33) is an affected source under the Reciprocating Internal Combustion Engine (RICE) MACT, 40 CFR 63, Subpart ZZZZ, *National Emission Standards for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines*. The RICE MACT was promulgated on June 15, 2004. As part of the design revisions,

the emergency generator will now function strictly as an emergency generator. Therefore, it meets the definition of emergency RICE and will only have to comply with the initial notification requirements of the RICE MACT.

Compliance Assurance Monitoring

Emissions of H₂SO₄ mist and fluorides from Emission Unit 31 are subject to the compliance assurance monitoring (CAM) requirements of 40 CFR Part 64. Associated impacts due to the design revisions are listed in the following table.

TABLE 4.1 – CAM Plan for H₂SO₄ Mist and Fluorides

Applicable CAM Requirement	H ₂ SO ₄ Mist	Fluorides
General Requirements	26.6 lb/hr 3 hour rolling average	1.55 lb/hr 3 hour rolling average
Monitoring Methods and Location	SO ₂ CEMs plus initial source test, weekly coal sampling (as received) with quarterly coal composites. WESP liquid flow rate, voltage, secondary currents and/or operating parameters, in conjunction with initial performance tests to establish excursion and exceedance, shall be monitored	SO ₂ CEMs plus initial source test, weekly coal sampling (as received) with quarterly coal composites
Indicator Range	Initial source testing to establish correlation to SO ₂ and coal quality, then establish SO ₂ CEM and coal range appropriate	Initial source testing to establish correlation to SO ₂ and coal quality, then establish SO ₂ CEM and coal range appropriate
Data Collection Frequency	Continuous SO ₂ CEM, weekly coal sampling (as received) with quarterly coal composites	Continuous SO ₂ CEM, weekly coal sampling (as received) with quarterly coal composites
Averaging Period	3 hour rolling	3 hour rolling
Recordkeeping	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records	Coal quality information will be kept in a designated hard copy or electronic archive, plus CEM data system records
QA/QC	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations	WFGD/WESP will be maintained and operated in accordance with manufacturer specifications and recommendations

The use of a CEM that provides results in units of the appropriate standard for the pollutant of interest and meets the criteria in 40 CFR 64.3(d)(2) is considered presumptively acceptable CAM. Additionally, the condition 6(b) for Emission Unit 31 in the permit incorrectly identified that the owner or operator report the number of excursions above an opacity trigger level. This condition has been removed from the permit.

PSD Requirements

The following table illustrates the subsequent optimizations of the proposed project.

TABLE 4.2 – Project Potential to Emit for Pollutants Requiring PSD Review

Pollutant	PTE (tpy)	Significant Emissions Rate * (tpy)
Carbon monoxide (CO)	3,050.2	100
Particulate matter (PM/PM ₁₀)	559.0	25/10
Volatile organic compounds (VOC)	97.5	40
Fluorides	6.8	3
Sulfuric Acid (H ₂ SO ₄) Mist	116.5	7

* Significant emission rate as given in 401 KAR 51:001 Section 1(221).

The proposed project with project revisions still constitutes a major modification for those pollutants listed in Table 4.2. PSD review applies to regulated pollutants for which there will be a net emissions increase that is significant as defined in 401 KAR 51:001, Section 1(221). For these pollutants, LG&E has performed a Best Available Control Technology (BACT) demonstration and an ambient air quality analysis as required by the Division. The proposed project is not significant with respect to NO_x, SO₂, lead, hydrogen sulfide, total reduced sulfur, reduced sulfur compounds or any other PSD-regulated pollutant. Pursuant to Section 112(b)(6) of the CAA, and 401 KAR 51:001 Section (1)(210) and (1)(221), no HAP is subject to PSD review. The proposed project revisions do not alter the original PSD applicability that was based on the information provided in the 2004 Application.

BEST AVAILABLE CONTROL TECHNOLOGY REVIEW

The Division reevaluated BACT for the project revisions and has determined that the BACT emission limits established in the January 2006 permit remain unchanged.

BACT for New SPC Boiler

The changes for Table 5-1 are in the Emissions Standard column from a 30 day rolling average to a 3 hour rolling average, for VOCs, Fluorides, and Sulfuric Acid Mist..

TABLE 5.1 – BACT Summary for New SPC Boiler (Emission Unit 31)

ID No.	Emissions Unit/Process	Pollutant	Best Available Control Technology	Emission Standard
31	Supercritical Pulverized Coal Fired Utility Boiler Operation limitation: None	CO	Proper Boiler Design & Operation	0.1 lb/mmBtu (30 day rolling average)
		PM/PM ₁₀	PJFF (Filterable) & WFGD/WESP (Condensable)	0.018 lb/mmBtu (Filterable & Condensable) (average of three 1-hour tests)
		VOCs	Proper Boiler Design & Operation	0.0032 lb/mmBtu (3 hour rolling average)
		Fluorides	Proper Boiler Design & WFGD	1.55 lb/hr (3 hour rolling average)
		Sulfuric Acid Mist	Proper Boiler Design & WFGD/WESP	26.6 lb/hr (3 hour rolling average)

Note: LG&E has also proposed an emission limitation of 0.015 lb/mmBtu (Filterable) on a 3-hour rolling average to meet U.S. EPA's revisions to 40 CFR Part 60, Subpart Da.

Nitrogen Oxide (NO_x)

The applicant had proposed that the NO_x emission limitation be set at 4.17 tons/day and 1,506.72 tons per year, which is based on a rate of 0.05 lb/MMBtu heat input on a 24-hour average. This equates to hourly emissions are 348 lbs/hr on a 24 hour basis.

Sulfur Dioxide (SO₂)

For the project optimizations, the applicant is proposing to use a WFGD system as the SO₂ control technology for Emission Unit 31. The applicant had proposed that the SO₂ emission limitation for Emission Unit 31 be set at 8.94 tons/day and 3,263.1 tons per year, which is based

on a rate of 0.11 lb/MMBtu heat input on a 24-hour average. This equates to hourly emissions of 746 lbs/hr on a 24 hour basis.

Carbon Monoxide (CO)

For the project optimizations, the applicant had proposed that the CO emissions shall not exceed 0.10 lbs/MMBtu from Emission Unit 31 based on a 30 day rolling average. In addition, a short term limit of 0.5 lbs/MMBtu has been set to ensure protection of the NAAQS. The Division will still consider proper boiler design and operation as BACT for CO emissions.

Particulate (PM/PM₁₀)

Particulate matter emissions from the new SPC boiler are primarily the result of ash content and other contaminants in the fuel. There are several control technologies for removing particulates from a gas stream but a PJFF and a dry ESP have the highest control efficiency of any of the particulate matter control options, and therefore, according to the “top-down” approach, were previously considered.

Dry Electrostatic Precipitator (DESP):

A DESP is being installed as part of the project revisions in order to collect saleable fly ash prior to potential fly ash contamination due to PAC injection prior to the PJFF for Hg control. As mentioned earlier, the installation of the DESP does not affect the BACT emission limits for particulate of 0.018 lb/MMBtu or filterable particulate of 0.015 lb/MMBtu established in the January 2006 Permit as Condition 2a or 2b for Emission Unit 31, respectively.

Fluorides

For the project optimizations, WFGD scrubber technology for SO₂ and a fluorides emission limitation of 1.55 lb/hr, based on a 3 hour rolling average, is considered BACT for the control of fluorides.

Sulfuric Acid (H₂SO₄) Mist

Alkali Injection Systems:

As part of the proposed project revisions, the applicant is proposing to inject hydrated lime prior to the PJFF to enhance bag conditioning and coincidentally reducing SO₃ emissions for some fuel combinations. This has not been proposed as an alternative SO₃ emission reduction technology. The Division has determined that the WESP by itself is BACT and sufficient to meet the BACT emission limit established by the January 2006 permit.

Startup and Shutdown

The emission limitations identified above do not apply during periods of startup and shutdown of the new SPC boiler (Emission Unit 31). The BACT determinations and associated emissions levels discussed above were determined based on normal operating conditions that allow the use of pollution control technologies. Some of these control technologies cannot be used to their full or partial potential during startup or shutdown for safety and other reasons. In addition, it is technically infeasible to monitor VOC, sulfuric acid mist, and fluoride emissions during startup and shutdown. Pursuant to 401 KAR 51:017, emissions during startup and shutdown shall be included in determining compliance with tons per year limits specified in the current permit and the owner or operator shall utilize good work and maintenance practices and manufacturer's recommendations to minimize emissions during, and the frequency and duration of, such startup and shutdown events. These practices and the supercritical design of boiler constitute BACT for startup and shutdown operations of the new SPC boiler.

A. *PM/PM₁₀-Material Handling*

For the proposed project revisions, the coal material handling system will be modified to reflect the relocation of coal conveyor E-2, along with additional coal conveyors E-3 and E-4. Therefore, two dust collection devices proposed on the existing coal material handling system and one from the existing active limestone storage building will be removed. These material handling systems with higher utilization capability were permitted under the initial source wide Title V permitting action and does not need a revised BACT review.

PM/PM₁₀-Cooling Towers

As part of the proposed project revisions, the applicant is now using a new 12-cell linear mechanical draft cooling tower (LMDCT) with a 0.0005 percent drift rate. The Division has established that the proposed technology and emission rates are BACT for the cooling towers. Additionally, the applicant proposed to upgrade the drift eliminators on the existing natural draft cooling tower from 0.008 percent drift rate to 0.0005 percent drift rate.

B. *Auxiliary Steam Boiler*

For the proposed project optimizations, the auxiliary steam boiler will increase in size to a 100 MMBtu/hr, unit and replace the three existing boilers utilized for Unit 1. The boiler will minimize emissions by utilizing low NO_x burners and firing ASTM Grade No. 2-D S15 (ultra low sulfur diesel) or equivalent fuel. The hours of operation for the boiler are capped at 2,000 hours per year. The proposed design and operation of the boiler constitute BACT.

C. Emergency Generator

As previously stated for the 2004 application, the applicant proposed to install a 1.25 MW emergency generator. The Division considered the use of ASTM Grade No. 2-D S15 (ultra low sulfur diesel-ULSD) or equivalent fuel and limiting the operation of the generator to 1000 hours per year. For the proposed project optimizations, the hours of operation will now be limited to no more than 52 hours or less per year to constitute BACT.

D. Emergency Diesel Fire Water Pump Engine

This unit has been removed as part of the project revisions. Subsequently, this emission source will be removed from the permit and Item 22 of the Insignificant Activities list of the permit will reflect only one fire water pump engine.

E. Project Emission Units

The following corrected table identifies emission unit and control devices affected by the Project:

TABLE 5.2 – Project Emission Units

Emission Units		Air Pollution Control Devices	
ID. No.	Description	ID. No.	Description
31	6,942 mmBtu/hr Supercritical Pulverized Coal Fired Boiler; ASTM Grade No. 2-D S15 (ultra low sulfur diesel-ULSD) or equivalent fuel for startup and stabilization	None	Equipped with SCR, Baghouse PJFF, WFGD & WESP. As part of the optimizations, DESP, PAC and hydrated lime injection are being added
32	100 mmBtu/hr Auxiliary Steam Boiler firing ASTM Grade No. 2-D S15 (ultra low sulfur diesel-ULSD) or equivalent fuel.	None	None
33	Emergency Generator firing ASTM Grade No. 2-D S15 (ultra low sulfur diesel-ULSD) or equivalent fuel	None	None
34-35	Active Southwest Fossil Fuel Pile “A” and Southeast Fossil Fuel Pile “B”	None	Compaction and Water Suppression
7-9	Fossil Fuel Handling Operations	36-39	Dust Collectors, Partial Enclosures, Low Pressure Drop, Water Suppression, and Hoods
11	Limestone Handling and Processing	40	Enclosure, Low Pressure Drop, Water Suppression, and Hoods

Emission Units		Air Pollution Control Devices	
ID. No.	Description	ID. No.	Description
20	Existing Natural Draft Cooling Tower for Emission Unit 31	None	0.0005% Drift Eliminators*
41	Linear Mechanical Draft Cooling Tower for Emission Unit 1	None	0.0005% Drift Eliminators
42	Fly Ash Storage Silos	42	Dust Collector
43	Waste Ash Storage Silo	43	Dust Collector (Bin Vent Filter)
44	PAC Storage Silo	44	Dust Collector (Bin Vent Filter)
45	Hydrated Lime Storage Silo	45	Dust Collector (Bin Vent Filter)

*Emission Unit 20 will continue to operate (drift eliminators will remain at 0.008%) and service Emission Unit 1 until a period during construction of Emission Unit 31. At that time, Emission Unit 20 will be modified to service Emission Unit 31. However, before Emission Units 20 and 31 commence operation, Emission Unit 20's drift eliminators will be replaced to achieve 0.0005%.

The units listed above are considered separate emission units because they are individual activities that emit or have the potential to emit regulated air pollutants. Emission Unit is defined at 401 KAR 51.001 Section 1(66) as any part of a stationary source that emits or has the potential to emit any regulated NSR air pollutant. This term is not meant to alter or affect the definition of the term "unit" for purposes of Title IV of the Act [40 CFR 70.2]. However, similar emission units were combined in this permit into one emission unit ID to simplify the permit. These emission units have the same applicable requirements.

H. Insignificant Activities/Applicable Regulations

401 KAR 52:020 Section 6 allows sources to separately list in the permit application activities that qualify as “insignificant” based on potential emissions. Insignificant activities have the potential to emit below 5 tpy for all nonhazardous air pollutants and ½ ton per year for combined HAPs. The activities that qualify as “insignificant” are not exempt from compliance demonstration and applicable requirements or any other requirements of the PSD/Title V permit. The following table has been adjusted for the project optimizations to describe the associated insignificant activities.

TABLE 5.3 – Project Insignificant Activities

Insignificant Activities Description and Applicable Regulation(s)	
1. Two station #2 fuel oil tanks, each 100,000 gallons (401 KAR 59:050), and auxiliary boiler day tank storing #2 fuel oil with a size of 16,000 gallons. General recordkeeping requirements - 40 CFR 60.116b(a) and (b)	401 KAR 59:050 40 CFR 60.116b(a) and (b)
2. Metal degreaser using a maximum throughput of 832 gallons/year solvent.	NA
3. 3,000 gallon unleaded gasoline storage tank.	NA
4. 3,000 gallon diesel storage tank.	NA
5. 1,100 gallon used oil storage tank.	NA
6. 1,100 gallon #1 fuel oil tank.	NA
7. Wet fly ash collection system	401 KAR 59:010
8. Infrequent evaporation of boiler cleaning solutions.	NA
9. Infrequent burning of de minimis quantities of used oil for energy recovery.	NA
10. Paved and Unpaved Roads.	401 KAR 63:010
14. Gypsum Storage Piles	401 KAR 63:010
15. Coal and Storage Piles (Inactive Outdoor Piles)s	401 KAR 63:010
16. Bottom Ash and Debris Collection Basin	401 KAR 63:010
17. Bottom Ash Reclaim Operation	401 KAR 63:010
18. Three dry bulk fly ash transport trailers	401 KAR 59:010
19. Maintenance Shop Activities	NA
20. Miscellaneous Water Storage Tanks	NA
21. Anhydrous Ammonia Storage Tanks	401 KAR 68
22. Fire Water Pump Engine	NA ^[11]

I. Applicable Requirements

Table 5.4 has been revised to list the emission units and their applicable requirements for the project revisions.

TABLE 5.4 – Project Applicable Requirements

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
31 750 MW SPC- Fired Boiler Primary Fuel: Coal	PM/ PM10	0.015 lb/mmBtu (filterable) based on a 3- hour rolling average 0.018 lb/mmBtu (filterable & condensable) based on an average of 3 1-hour tests	401 KAR 59:016 Section 3(1)(b) & 6(1) 401 KAR 60:005 Section 3(1)(c) 401 KAR 51:017 (filterable and condensable only) 40 CFR Part 60, Subpart Da 40 CFR Parts 75	Continuous Emissions Monitoring	Reports for all required monitoring	Initial and annual performance testing/ U.S. EPA Reference Methods 5, 9, 201 or 201A, & 202, or alternative method approved in permit, or other approved alternative method
	SO ₂	8.94 tpd 1.2 lb/mmBtu and 90% reduction or 70% reduction when emissions are less than 0.6 lb/mmBtu, based on 30- day rolling average 2.0 lb/MWh gross energy output, based on 30-day rolling average	401 KAR 59:016, Section 4(1) 401 KAR 60:005 Section 3(1)(c) 40 CFR Part 60, Subpart Da 40 CFR Parts 75 & 72	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Testing using CEMs

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
	NO _x	4.17 tpd 0.6 lb/mmBtu (65% reduction,) based on a 30- day rolling average 1.6 lb/MWH gross energy output, based on a 30 day rolling average 1.0 lb/MWh gross energy output, based on a 30-day rolling average	401 KAR 59:016 Sections 5(1)(c), 6(2), 5(2) 401 KAR 60:005 Section 3(1)(c) 40 CFR Part 60, Subpart Da 40 CFR Parts 75 & 72	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Testing using CEMs
	CO	0.10 lb/mmBtu based on a 30 day rolling average 0.5 lb/mmBtu on a 3-hr rolling average.	401 KAR 51:017	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Testing using CEMs
	VOC	0.0032 lb/mmBtu based on a 3- hour rolling average	401 KAR 51:017	CO CEM use CO emissions as surrogate for VOC emissions	Reports of all required monitoring	Initial and annual Performance Tests/EPA reference methods 18 or 25
	Fluoride	1.5 lb/hr based on a 3 hour- day rolling average	401 KAR 51:017 40 CFR Part 64	SO ₂ CEMs, use SO ₂ emissions as surrogate for fluoride emissions	Reports of all required monitoring	Initial Performance Tests/EPA reference method 26A

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
	Sulfuric Acid Mist	26.6 lb/hr based on a 3- hourly rolling average	401 KAR 51:017 40 CFR Part 64	SO ₂ CEMs, WESP liquid flow rate, voltage, secondary currents and/or operating parameters,	Reports for all required monitoring	Initial Performance Tests/EPA reference method 8
	Hg	13 x 10 (E-6) lb/MWh gross energy output, based on a 12- month rolling average Formula per 40 CFR 60.45a	401 KAR 60:005, Section 3(1)(c) 40 CFR Part 60, Subpart Da	Continuous Emissions Monitoring	Reports for all required monitoring	Initial Performance Tests/EPA reference method 29
	Pb	0.55 tpy	401 KAR 51:017	PM CEMs, use PM emissions as surrogate for Pb emissions	Reports for all required monitoring	Initial and annual performance tests/EPA Methods 12 or 29
32 Auxiliary Steam Boiler	PM/PM10	0.03 lb/mmBtu	401 KAR 59:015, Section 4(1)(c) 401 KAR 51:017 401 KAR 60:005, Section 3(1)(e) 40 CFR Part 60, Subpart Dc 40 CFR 60.43c(e) (proposed) 40 CFR Part 63, Subpart DDDDD	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	Certification per 40 CFR 63.7506

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
	CO	400 ppmv, on a dry basis corrected to 3% oxygen, based on a 30-day rolling average	401 KAR 51:017 40 CFR Part 63, Subpart DDDDD	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	Certification per 40 CFR 63.7506
	SO ₂	Use of ASTM Grade No 2-D S15 or equivalent fuel oil	401 KAR 59:015 Section 5(1)(b) 401 KAR 51:017 401 KAR 60:005, Section 3(1)(b)	Monitor hours of operation and fuel oil sulfur content and heating value	Reports of all required monitoring	Certification per 40 CFR 63.7506
	HCl	0.0005 lb/mmBtu	40 CFR Part 63, Subpart DDDDD	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	Certification per 40 CFR 63.7506
	All Pollutants	Use of ASTM Grade No 2-D S15 or equivalent fuel oil Operate, except for testing purposes, only when Emission Unit 31 is operating at less than 50% load Operate no more than 1,000 hours in any 12- month period	401 KAR 51:017	Monitor hours of operation and fuel oil sulfur content and heating value	Reports for all required monitoring	

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
33 Emergency Generator						
	NO _x + NMHC	6.4 g/kw-hr (4.8 g/hp-hr)	40 CFR part 60 Subpart IIII	Installing a non- resettable hour meter	reporting and notification requirements pursuant to 40 CFR 60.4214.	Demonstrate compliance by buying a manufacturer certified engine
	CO	3.5 g/kw-hr (2.6 g/hp-hr)	40 CFR part 60 Subpart IIII	None	reporting and notification requirements pursuant to 40 CFR 60.4214.	Demonstrate compliance by buying a manufacturer certified engine
	PM	0.20 g/kw-hr (0.15 g/hp-hr)	40 CFR part 60 Subpart IIII	None	reporting and notification requirements pursuant to 40 CFR 60.4214.	Demonstrate compliance by buying a manufacturer certified engine
	All pollutants	Use of ASTM Grade No 2-D (ultra low sulfur diesel)S15 or equivalent fuel Operate, except for testing purposes, only when Emission Unit 31 is operating at less than 50% load Operate no more than 52 hours in any 12- month period	401 KAR 51:017			

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
34-35 Fossil Fuel Handling Operations – Coal Piles “A & B”	PM	None	401 KAR 51:017 401 KAR 63:010	Maintain Records of Coal received and processed and weekly (Monday – Friday) visual observation	50:055 Section 1, 52:020 Section 21 & 22	Method 9
37 and 39 Fossil Fuel Handling Operations, Dust Control Device, and Associated Systems Note: Emission Units 36 and 38 have been removed from the design.	PM	None	401 KAR 51:017 401 KAR 60:005 40 CFR Part 60, Subpart Y	Maintain Records of Coal received and processed and weekly (Monday – Friday) visual observation	50:055 Section 1, 52:020 Section 21 & 22	Method 9
40 Limestone Handling and Processing	PM	None	401 KAR 51:017 401 KAR 60:670 40 CFR Part 60, Subpart OOO	Maintain Records of Limestone received and processed and weekly (Monday – Friday) visual observation	50:055 Section 1, 52:020 Section 21 & 22	Method 9
20, 41 Cooling Towers	PM	401 KAR 63:010, Section 3	401 KAR 51:017 401 KAR 63:010	Maintain Records of Maximum pumping capacity and total dissolved solids	50:055 Section 1, 52:020 Section 21 & 22	CTIACT- 140. Monthly measurement of total dissolved solids content of circulating water
42 Fly Ash Loading System	PM	401 KAR 59:010	401 KAR 51:017 401 KAR 63:010	Maintain records of ash conveyed and visual observation		Method 9

Emission Unit ID	Pollutant	Emission Limitation / Operational Restrictions	Applicable Requirements	Monitoring Record keeping	Reporting	Compliance /Testing
43 Waste Ash Storage	PM	401 KAR 59:010	401 KAR 51:017 401 KAR 63:010	Maintain records of ash conveyed and visual observation		Method 9
44 PAC Storage	PM	401 KAR 59:010	401 KAR 51:017 401 KAR 63:010	Maintain records of ash conveyed and visual observation		Method 9
45 Hydrated Lime Storage	PM	401 KAR 59:010	401 KAR 51:017 401 KAR 63:010	Maintain records of ash conveyed and visual observation		Method 9

J. BACT SUMMARY

The Division has reviewed the proposed changes to the project and has determined that the Division's prior equipment specific BACT determinations are still applicable and are summarized below.

Auxiliary Boiler

The proposed new auxiliary boiler will continue to comply with the same emission limits as the previously proposed smaller boiler. Since the prior BACT determination on the auxiliary boiler was not contingent on the size of the proposed unit and was not affected by the size increase, the prior BACT determination for the auxiliary boiler is still applicable.

DESP

The DESP is being voluntarily installed on Emission Unit 31 to collect saleable fly ash rather than achieving PM emission control. Any PM emissions control will be an insignificant coincidental benefit. The previously applicable BACT PM emission limits for Unit 2 will continue to apply irrespective of DESP installation and operation, and will be met by utilizing a PJFF.

New Material Silos (PAC, Waste Ash, and Hydrated Lime)

The BACT emission control for these systems is enclosed designs for transfer and storage of materials with the final stage of transport air cleaning via cartridge filter systems prior to discharge to the atmosphere. These systems will meet the same requirements as previously determined as BACT for the similar facility systems.

Existing Material Handling Conveyor Systems

EPA has issued numerous PSD guidance documents as early as 1981 which hold that an emission unit (the existing material handling system) which is debottlenecked due to a modification before or after the existing unit (in this case the addition of Emission Unit 31) does not require the existing unit (the existing material handling system) to be subject to a new BACT analysis. This long standing interpretation was recently confirmed by EPA's proposal on September 14, 2006 (Federal Register Vol. 71; pg. 54240.) in which EPA notes a legal causation relationship. EPA guidance documents confirm that the existing coal and reagent material handling operations are not subject to reevaluation of BACT as part of the TC2 project because this "emission unit" was previously permitted to handle the additional material throughput. The emission increase of PM₁₀ has been appropriately accounted for as part of the PTE calculation and included in the Project's PSD applicability determination. Furthermore, these emissions have been included in the air dispersion modeling to demonstrate compliance with applicable air quality thresholds. The existing equipment will therefore continue to operate under current permit limits and level of emission control currently being achieved.

New Material Handling Conveyor Systems

The new material handling equipment proposed for the project revisions will have appropriate BACT technology applied to control emissions of PM₁₀, as determined for other project material handling equipment, which will include enclosures and a dust collection device. Therefore, the prior BACT determinations are extended to this additional material handling equipment.

Emergency Generator

The Emergency Generator is reducing hours of operation to 52.

2. AIR QUALITY IMPACT ANALYSIS

As has been previously noted, the revisions do not result in significant net emissions increase of NO_x or SO₂ or any other pollutant that was not previously analyzed as part of the 2004 Application. Pursuant to 401 KAR 51:017 Section 12, the applicant has provided an analysis of the air quality impacts of the modification.

The purpose of these analyses is to demonstrate that allowable emissions from the proposed project will not cause or contribute to air pollution in violation of:

1. A national ambient air quality standard in an air quality control region; or
2. An applicable maximum allowable increase over the baseline concentration in an area.

A. *Modeling Methodology*

As part of the design revisions, the application contains AERMOD air dispersion modeling analysis for PM/PM₁₀ and CO to determine the maximum ambient concentrations attributable to the proposed project for each of these pollutants for comparison with:

1. The Significant Impact Levels (SIL) found in 40 CFR 51.165 (b)(2).
2. The Significant Air Quality Impact levels (SAI) found in Regulation 401 KAR 51:017, Section 6 Section 7(5).
3. The Class I and Class II Ambient Air Increments found in Regulation 401 KAR 51:017, Section 2.
4. The National Ambient Air Quality Standards (NAAQS) found in Regulation 401 KAR 53:010, Ambient air quality standards.

All applicable ambient air quality concentration values are presented in Table 6.1. Based on U.S. EPA procedures, if the maximum predicted impacts for any pollutant are found to be below the SILs, it is assumed that the proposed facility cannot cause or contribute to a violation of the PSD pollutant increments or the national ambient air quality standards (NAAQS). Therefore, no further modeling would be required for such a pollutant. The applicant may also be exempted from the ambient monitoring data requirements if the impacts are below the significant monitoring concentrations or SAI. The SAI levels determine if the applicant will be required to perform pre-construction monitoring. If the modeled impacts equal or exceed the SAI levels, pre-construction monitoring may be required. However, if existing air quality data is available that is representative of the air quality area in question an exemption may be granted. As shown in the application, the modeled impacts as compared to the SAI levels were not exceeded for the PM₁₀ 24-hour and annual or CO 1 hour and 8-hour periods. Based on the information contained in the air permit application, the applicant requested a waiver from ambient monitoring. The Division reviewed the air permit application and associated air dispersion modeling and determined the location of the existing monitors, quality of the data, and the data's correctness all met the requirements listed in the NSR guidance manual. Therefore, the applicant is exempted from the pre-construction ambient monitoring data requirements.

TABLE 6.1 – Ambient Air Quality Concentration Values

Pollutant	Averaging Period	SIL ($\mu\text{g}/\text{m}^3$)	SAI ($\mu\text{g}/\text{m}^3$)	PSD Class II Increments ($\mu\text{g}/\text{m}^3$)	NAAQS ($\mu\text{g}/\text{m}^3$)
PM/PM ₁₀	Annual	1	NA	17	50
	24-hour	5	10	30	150
CO	8-hour	500	575	NA	10000
	1-hour	2000	NA	NA	40000

The applicant used the AERMOD model (Version 04300) in the analysis. The AERMOD model fulfills the requirements of Supplement C of the Guideline on Air Quality Models (Appendix W to 40 CFR Part 51). All of the parameters used in the modeling analysis for each pollutant appear satisfactory and consistent with the prescribed usage for this model. Per U.S. EPA guidance, the AERMOD model was run with the regulatory default option in a sequential hourly mode using five years of meteorological data. Surface data and concurrent upper air data used were based on weather observations taken at the National Weather Service (NWS) station at Standiford Field in Louisville, Kentucky and Dayton, Ohio, respectively, from 1987 to 1991. To reflect the modeled impacts used for determining compliance with the SIL and SAI, a short term permit limit of 0.5 lbs/MMTUtu on a three hour average has been set for this permit. This limit is to ensure protection of the NAAQS and is not meant to be a BACT limit. The applicant's modeling in support of the January 2006 permit was performed with the Industrial Source Complex Short-Term (ISCST3) model. It has been determined that the addition of the proposed DESP, PAC, and lime injection does not change the Emission Unit 31's exhaust gas temperature, exit velocity, or proposed emissions and therefore the previous ISCST analysis is valid.

Similarly, the applicant did not perform an additional Class I modeling analysis for Mammoth Cave National Park for the design revisions. The nearest park boundary is approximately 155 km (96 miles) to the South-Southwest of the proposed project. The original analysis provided in the 2004 Application included only the main boiler as all other emission sources were determined not to affect the Class I area. As previously noted, the modification did not affect the main boiler's proposed emissions or stack exhaust characteristics. Therefore, original Class I modeling provided in 2004 Application is still valid.

B. Modeling results - Class II Area Impacts

The proposed facility will be located in Trimble County, a Class II area. The applicant modeled the impact of the potential emissions from the proposed project on the ambient air quality as part of the design revisions and the results of the modeled impacts on the Class II area have been presented in Table 6.2.

The modeling results show that the maximum impacts from the proposed Project for PM₁₀ annual and CO 1-hour and 8-hour averaging periods are less than the U.S. EPA prescribed significant impact levels (SIL) and no further analyses are required. However, the modeling results show that the maximum impacts from the proposed facility for PM₁₀ for the 24-hour period exceed the SIL and require a PSD increment consumption analysis and a comparison to determine compliance with the National Ambient Air Quality Standards (NAAQS).

The applicant performed additional analysis to demonstrate compliance with the Class II PSD increment and the NAAQS. Because the PM₁₀ annual SIL modeling produced maximum impacts that were within 10% of the threshold, applicant included PM₁₀ annual modeling in these analyses. The modeling results for the PSD increment analysis for the proposed Project, included in Table 6-3, are less than the U.S. EPA prescribed increment levels and no further analyses are required. For the NAAQS analysis, the applicant has appropriately identified and used regional background PM₁₀ concentration values in the analysis from a monitor located in Louisville, Kentucky. The NAAQS modeling results, including background, are less than the U.S. EPA prescribed NAAQS levels and no further analyses are required. The NAAQS analyses results are included in Table 6-4.

Detailed descriptions of the modeling inputs and results are in Section 5 and Appendix F of the 2007 Application.

Because EPA has proposed, but not finalized PM_{2.5} implementation guidance, the Division has utilized PM₁₀ as a surrogate for PM_{2.5} in the interim prior to issuance of final guidance. Trimble County has not been designated a PM_{2.5} nonattainment area. It does border Clark County, Indiana, a PM_{2.5} nonattainment area. An air dispersion modeling analysis has been performed to include part of Clark County, Indiana. Specifically, the results from the Class II PM₁₀ air dispersion modeling indicated that there was no significant impact (exceedances of the SIL) of PM₁₀ emissions on a 24-hour or annual basis on the area including part of Clark County, Indiana. The Cincinnati PM_{2.5} nonattainment area is located approximately 40 miles northeast of the proposed Unit 2 project and does not border Trimble County. Due to the distance between the Project and this area, the proposed project would not have a significant impact on the Cincinnati PM_{2.5} nonattainment area.

TABLE 6.2 – Applicant’s Modeled Predicted Impacts

Pollutant	Averaging Period	SIL ($\mu\text{g}/\text{m}^3$)	SAI ($\mu\text{g}/\text{m}^3$)	Max Impact of Emission ($\mu\text{g}/\text{m}^3$)	Exceedance of SIL	Preconstruction Monitoring Required
PM/PM ₁₀	Annual 24-hour	1	NA	0.92	No	NA
		5	10	9.97	Yes	No
CO	8-hour 1-hour	500	575	87	No	No
		2000	NA	202	No	NA

TABLE 6.3 – Applicant’s Modeled Increment Consumption

Pollutant (PM/PM ₁₀)	Averaging Period	Class II Increment ($\mu\text{g}/\text{m}^3$)	Project Class II Increment Consumption ($\mu\text{g}/\text{m}^3$)
PM/PM ₁₀	Annual 24-hour	17	3
		30	22

TABLE 6.4 – Applicant’s Modeled NAAQS

Pollutant (PM/PM ₁₀)	Averaging Period	NAAQS ($\mu\text{g}/\text{m}^3$)	Project NAAQS Impact ($\mu\text{g}/\text{m}^3$)
PM/PM ₁₀	Annual 24-hour	50	27
		150	87

3. ADDITIONAL IMPACTS ANALYSIS

401 KAR 51:017 Section 13 requires an applicant for a PSD permit to provide an analysis of the impairment to visibility, soils and vegetation that will occur as a result of the project and projected growth associated with the project.

A. *Growth Analysis*

The proposed project, as reported in the application, will employ approximately 600 to 700 personnel during the construction phase. The project will employ approximately 30 to 40 people on a permanent basis. It is a goal of the project to hire from the local community where possible. There should be no substantial increase in community infrastructure, such as additional school

enrollments. The proposed project is also not expected to result in an increase in secondary emissions associated with non-project related activities.

B. Soils and Vegetation Impacts Analysis

The proposed project is located at the existing Trimble County Generating Station. While the initial modeling indicated the proposed Project exceed PSD SILs for PM₁₀ on a 24-hour basis along the facility boundary, the subsequent increment and NAAQS analyses resulted in impacts below applicable U.S. EPA prescribed thresholds. Therefore, the potential for adverse impacts to either soils or vegetation is minimal. It is concluded that no adverse impacts will occur to sensitive vegetation, crops or soil systems as a result of operation of the proposed project.

C. Visibility Impairment Analysis

As discussed previously in Section 6, the visibility analysis at Mammoth Cave National Park previously submitted using the visibility function in the CALPUFF model is still valid. The projected change in visibility associated with the operation of the proposed facility has been determined to be minimal as a result of the multiple control technologies that will be utilized. Additionally, Section 6 of the 2004 Application contains a visibility analyses for the nearby City of Bedford, Kentucky. As previously noted, the proposed changes do not change Emission Unit 31's exhaust gas temperature, exit velocity, or proposed emissions and therefore the previous visibility analysis conducted for Bedford, Kentucky is valid.

4. CONCLUSION AND RECOMMENDATION

In conclusion, considering the information presented in the application, the Division has made a preliminary determination that the proposed project meets all applicable requirements:

1. All the emission units are expected to meet the requirements of BACT for each regulated pollutant for which there will be a significant net emission increase. Additionally, each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emission standard and standard of performance under 40 CFR Parts 60, 61, 63 and 64 will also be met.
2. Emissions from the proposed project will not cause or contribute to a violation of the NAAQS or any Class I or Class II Ambient Air Increments. Ambient air quality impacts on Class II area are expected to be below the applicable U.S. EPA prescribed levels. No adverse impact is expected on any Class I area.
3. Impacts on soil, vegetation, and visibility have been predicted to be minimal.

The Division has made a preliminary determination to approve the application. A draft permit to authorization the construction and operation of the project at the Trimble County Generating Station located west of Bedford in Trimble County, Kentucky, containing conditions which ensure compliance with all the applicable requirements listed above has been prepared by the

Division and issued for public notice and comment. A copy of this preliminary determination will be made available for public review at the following locations:

1. Affected public at the Trimble County Clerk's office, Bedford, KY 40006-0262.
2. Division for Air Quality, 803 Schenkel Lane, Frankfort.
3. Division for Air Quality, Florence Regional Office, 8020 Veterans Memorial Drive, Suite 110, Florence, KY 41042-8960.

PREVIOUS PERMITTING ACTION: V-02-043R2

5. EXECUTIVE SUMMARY

Louisville Gas and Electric Company (LG&E), as operator, submitted an air permit application dated December 01, 2004, to construct a new 750 megawatt (MW) net nominal generating unit that will utilize supercritical pulverized coal (SPC) technology at its existing Trimble County Generating Station located west of Bedford in Trimble County, Kentucky. The new SPC boiler will be equipped with Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filters (PJFF), a Wet Flue Gas Desulfurization (WFGD) System, and a Wet Electrostatic Precipitator (WESP). It will exhaust through two exhaust flues located within an existing common chimney and will be equipped for ASTM Grade No. 2-D S15 or equivalent fuel oil for start-up and stabilization. Existing equipment at the Trimble County Generating Station includes the following: a 500 MW (nominal rated capacity) pulverized coal generating unit (Emissions Unit 1), six 160 MW (nominal rated capacity) simple cycle natural gas combustion turbines (Emissions Units 25-30), a natural draft cooling tower, coal/limestone/ash/gypsum material handling equipment, three auxiliary boilers, an emergency diesel generator, and fuel oil storage tanks. The natural draft cooling tower, coal/limestone/ash/gypsum material handling equipment, and fuel oil storage tanks will have increased utilization when the new SPC boiler becomes operational. The new facilities that will be constructed as part of this proposed project will include the SPC boiler (Emissions Unit 31), a linear mechanical draft cooling tower (LMDCT) for Emissions Unit 1, a coal blending facility, dust collectors and dust suppression equipment on material handling operations, an ash barge loading system/fly ash silos, an auxiliary steam boiler, a backup diesel generator, and an emergency diesel fire water pump engine. The seven existing combustion units (Emissions Unit 1 and Emissions Units 25 -30) are not part of the proposed major modification, and have previously gone through Prevention of Significant Deterioration (PSD) review. The proposed project constitutes a major modification of a major stationary source as defined in 401 KAR 51:017, Prevention of Significant Deterioration of Air Quality. The proposed project will result in a significant net emissions increase, as defined in 401 KAR 51:001 Section 1(146), of the following regulated air pollutants: particulate matter (PM &

PM₁₀), carbon monoxide (CO), volatile organic compounds (VOC), fluorides, and sulfuric acid (H₂SO₄) mist. The proposed project is not subject to PSD review for nitrogen oxides (NO_x) and sulfur dioxide (SO₂) based on contemporaneous and creditable emission reductions of NO_x and SO₂ from the existing PC boiler (Emissions Unit 1). The emissions reductions from Emissions Unit 1 will be such that there will be no significant net emissions increase of NO_x and SO₂ thus removing these two pollutants from this PSD review. In addition, the project will not emit lead above the significant emission rate for lead of 0.6 tons per year (tpy), set forth in 401 KAR 51:001 Section 1(221) and 40 CFR 51. Emissions from the project of hydrogen sulfide, total reduced sulfur, and reduced sulfur compounds will also be below significant emission levels and are therefore not subject to PSD review.

The Trimble County Generating Station is located in a county classified as “attainment” or “unclassified” for each of the PSD applicable pollutants pursuant to 401 KAR 51:010, Attainment Status Designations. The Trimble County Generating Station is an existing major stationary source under the PSD regulations as defined in 401 KAR 51:001, Section 1(120). The proposed project meets the definition of a major modification and is subject to evaluation and review under the provisions of the PSD regulation for PM & PM₁₀, CO, VOC, fluorides, and H₂SO₄ mist. A PSD review involves the following six requirements:

1. Demonstration of the application of Best Available Control Technology (BACT).
2. Demonstration of compliance with each applicable emission limitation under 401 KAR Chapters 50 to 65 and each applicable emissions standard and standard of performance under 40 CFR Parts 60, 61, and 63.
3. Air quality impact analysis.
4. Class I area impact analysis.
5. Projected growth analysis.
6. Analysis of the effects on soils, vegetation and visibility.

Furthermore, the source will also be subject to Title V, Title IV Phase II Acid Rain and NO_x SIP Call permitting. The Title V permitting procedures are contained in 401 KAR 52:020. The Title IV permitting procedures are within 401 KAR 52:020, Permits, 401 KAR 52:060, Acid Rain Permit, 40 CFR Part 76 and 40 CFR 97. NO_x SIP Call permitting procedures are within 401 KAR 51:160. This Statement of Basis addresses the proposed conditions of the PSD/Title V permit and the Title IV Phase II Acid Rain permit. The preliminary PSD determination is also provided within this Statement of Basis for the Title V permit. This review demonstrates that all regulatory requirements will be met and includes a draft permit that would establish the enforceability of all applicable requirements. This review is to ensure that the source shall be considered in compliance with all applicable requirements, as of the date of permit issuance for the applicable requirements that are specifically identified in the permit, and specifically identified requirements that have been determined to not be applicable to the source

Louisville Gas & Electric Company submitted a minor revision application to the Division on April 29, 2005 for a voluntary creditable decrease in emissions for the permitted Emission Unit 01, a 5,333 mmBtu/hr, pulverized coal-fired boiler installed in 1990. The creditable decrease in emissions will be 3,225 tons per year of sulfur dioxide. This permit will limit the twelve (12) month rolling total on the unit sulfur dioxide (SO₂) on the unit to 4,822 tons per year. The credible reduction is requested by the facility to net against future potential increase from the construction of the additional utility boiler (TC2). The practically enforceable creditable reduction is being done in accordance with new source review (NSR) rules. [401 KAR 51:001 and 401 KAR 51:017] Compliance with the emissions limit shall be demonstrated using continuous emission monitoring equipment which measures the emissions hourly and procedures required by 401 KAR 52:060 (acid rain program). The sulfur dioxide limit shall become effective January 1, 2006. A previous minor permit revision limited nitrogen oxide emissions from Unit 1 to 5,556 tons per year, a credible decrease of 1,485 tons per year. That limit was effective January 1, 2005.

6. BACKGROUND

On December 01, 2004, the Division received a permit application to construct and operate a SPC boiler, and associated support equipment, for electricity generation from LG&E. The application was logged administratively complete on January 29, 2005.

7. EMISSIONS ANALYSIS

The new SPC boiler (Emissions Unit 31) is equipped with Selective Catalytic Reduction (SCR), Pulse Jet Fabric Filters (PJFF), a Wet Flue Gas Desulfurization (WFGD) System, and a Wet Electrostatic Precipitator (WESP). Additional processes at the facility will include a ASTM Grade No. 2-D S15 or equivalent fuel oil-fired auxiliary steam boiler (to operate 1,000 hours or less per year); a diesel emergency fire water pump engine (to operate 52 hours or less per year); a backup diesel generator (to operate 1,000 hours or less per year); new coal blending system and associated material handling equipment; increased utilization of existing material handling equipment; increased utilization of the existing natural draft cooling tower; a linear mechanical draft cooling tower (LMDCT) for Emissions Unit 1; increased utilization of the existing fuel oil storage tanks; and an ash barge loading system/fly ash silos. Detailed descriptions of the plant processes and expected emissions at each emissions point and emissions unit are contained in the air permit application document (refer to Section 2.3 of the air permit application). In addition, hourly and annual emission rates and pollutant identification for each respective emission unit can be referenced from the application. Emissions were based on the maximum rated capacity of the proposed project, anticipated operating conditions, and 8,760 hours per year after control technologies were applied. The project's annual net emissions increases for PSD-regulated pollutants and mercury, as shown below in Table 3-1 and in Table 2-2 of the application, are

calculated for anticipated conditions while operating at 100% load. Evaluations at 50% and 75% load were also performed as well as for three potential coal fuels.

**TABLE 3.1 – Net Emissions Increase for
PSD-Regulated Pollutants**

Pollutants	Net Emissions Increase (tpy)
Carbon Monoxide (CO)	3,040.8
Nitrogen Oxides (NO _x)	38*
Particulate Matter (PM/PM ₁₀)	567.4
Sulfur Dioxide (SO ₂)	39**
Volatile Organic Compounds (VOC)	97.8
Sulfuric Acid (H ₂ SO ₄) Mist	116.6
Fluorides	6.8
Lead (Pb)	0.55
Total Reduced Sulfur	Negligible
Reduced Sulfur Compounds	Negligible
Hydrogen Sulfide	Negligible
Mercury (Hg) (non PSD pollutant)	0.043

* On January 4, 2005, the Division for Air Quality (Division) approved LG&E's minor permit revision that contained an enforceable emissions limit such that the consecutive twelve-month rolling total of NO_x emissions from Emissions Unit 1 shall not exceed 5,556 tpy. The emissions decrease for Emissions Unit 1 of 1,485 tpy of NO_x is realized as both contemporaneous and creditable. The proposed project is not subject to PSD review for NO_x.

** On May 2, 2005, the Division received LG&E's minor permit revision that contained an enforceable emissions limit such that the consecutive twelve month rolling total of SO₂ emissions from existing Emissions Unit 1 shall not exceed 4,822 tpy. The emissions decrease for Emissions Unit 1 of 3,225 tpy of SO₂ is realized as both contemporaneous and creditable. The proposed project is not subject to PSD review for SO₂.

As the notes to Table 3.1 indicate, LG&E has accepted a new lower limit on its allowable emissions of NO_x and SO₂ from the existing PC boiler (Emissions Unit 1). These lowered limits are less than Trimble's historical emissions and represent real reductions. These emissions reductions will offset nearly all of the NO_x and SO₂ emissions increases due to the proposed Project. Taken together, the emissions decreases at Emissions Unit 1 and the emissions increases due to the Project will result in a net emissions increase in NO_x of 38 tpy and in SO₂ of 39 tpy.

This netting analysis is based on the operation of 8760 hours/year at the rated capacity. Actual emissions are expected to be much less. These net emissions increases are not considered significant under 401 KAR 51:001 Section 1(221). Therefore, the Project is not subject to PSD BACT review for NO_x and SO₂.

Pursuant to 401 KAR 51:017, the creditable emissions reductions from Emissions Unit 1 were determined by the difference between Emissions Unit 1's post-change enforceable emissions limits and the pre-change baseline actual emissions (BAE). For an Electric Utility Steam Generating Unit (EUSGU), the BAE is calculated as the emission rate, in tons per year, based on the actual emissions determined over a consecutive 24-month period during the 60-month period preceding the contemporaneous emissions change. Specifically, the baseline look back period for Emissions Unit 1 is the 60-month period preceding the date on which an enforceable permit limit for SO₂ and NO_x is taken, respectively.

Capital investment and increased operating and maintenance (O&M) costs are required to implement the reductions at Emissions Unit 1. For NO_x, LG&E will reduce NO_x emissions through a combination of increased removal efficiency and increased SCR operating time. Additionally, for these reductions to be considered contemporaneous and therefore eligible for consideration in the netting analysis, they must occur within the period beginning 60-months before initiation of construction of the Project (construction of TC2 and associated equipment) and before the initial operation of the Project.

The Division has established that the change in method of operations for the existing Trimble County Generation Station is marked by the initiation of the change to Emissions Unit 1's NO_x and SO₂ emission limits by an enforceable permit action. Thus, the BAE for Emissions Unit 1 for netting purposes, on a pollutant-by-pollutant basis, begins 60-month period prior to, and ends on, the date of the enforceable permit action for NO_x and SO₂, respectively. Table 3.2 identifies the creditable decreases at Emissions Unit 1.

TABLE 3.2 – Creditable Emissions Decreases at Emissions Unit 1 (TPY)

	Baseline Actual Emissions	New Limits	Creditable Decreases
NO _x	7,041	5,556	1,485
SO ₂	8,047	4,822	3,225

LG&E submitted to the Division two minor revision applications on November 29, 2004 and, May 2, 2005, to establish the new limits reflected in Table 3.2. Compliance with the new limits shall be demonstrated using continuous emission monitoring equipment and procedures required by 401 KAR 52:060 (acid rain program). The enforceable annual tonnage limit for NO_x will be achieved using the installed selective catalytic reduction (SCR). The enforceable annual tonnage limit for SO₂ will be achieved using the upgraded wet limestone flue gas desulfurization (WFGD) system.

In order to determine the net emissions increases for the proposed Project for NO_x and SO₂, the Division determined the contemporaneous period for the Project and identified all emissions increases and decreases that are contemporaneous and creditable pursuant to 401 KAR 51:001 Section (1)(146). The contemporaneous period for the proposed Project is the period 60-months prior to the start of construction through the period in which the Project starts operation. For this Project, the construction period is projected at 5-years, resulting in a 10-year period. The Division has concluded that no other creditable emission increases or decreases have occurred within the contemporaneous period for the Project. The Trimble County Generating System was most recently subject to PSD review in January 2001 for the construction of six simple cycle natural gas combustion turbine peaking units. Table 3.3 summarizes the PSD netting for NO_x and SO₂.

TABLE 3.3 – PSD Netting Summary (TPY)

	Emissions Unit 1 Creditable Decreases	Project Emissions Increases	Net Emissions Increase	Significant Emissions Rate*
NO _x	1,485	1,523	38	40
SO ₂	3,225	3,264	39	40

* Significant emission rate as given in 401 KAR 51:001 Section 1(221)

CREDIBLE EVIDENCE:

This permit contains provisions which require that specific test methods, monitoring or recordkeeping be used as a demonstration of compliance with permit limits. On February 24, 1997, the U.S. EPA promulgated revisions to the following federal regulations: 40 CFR Part 51, Sec. 51.212; 40 CFR Part 52, Sec. 52.12; 40 CFR Part 52, Sec. 52.30; 40 CFR Part 60, Sec. 60.11 and 40 CFR Part 61, Sec. 61.12, that allow the use of credible evidence to establish compliance with applicable requirements. At the issuance of this permit, Kentucky has not incorporated these provisions in its air quality regulations.